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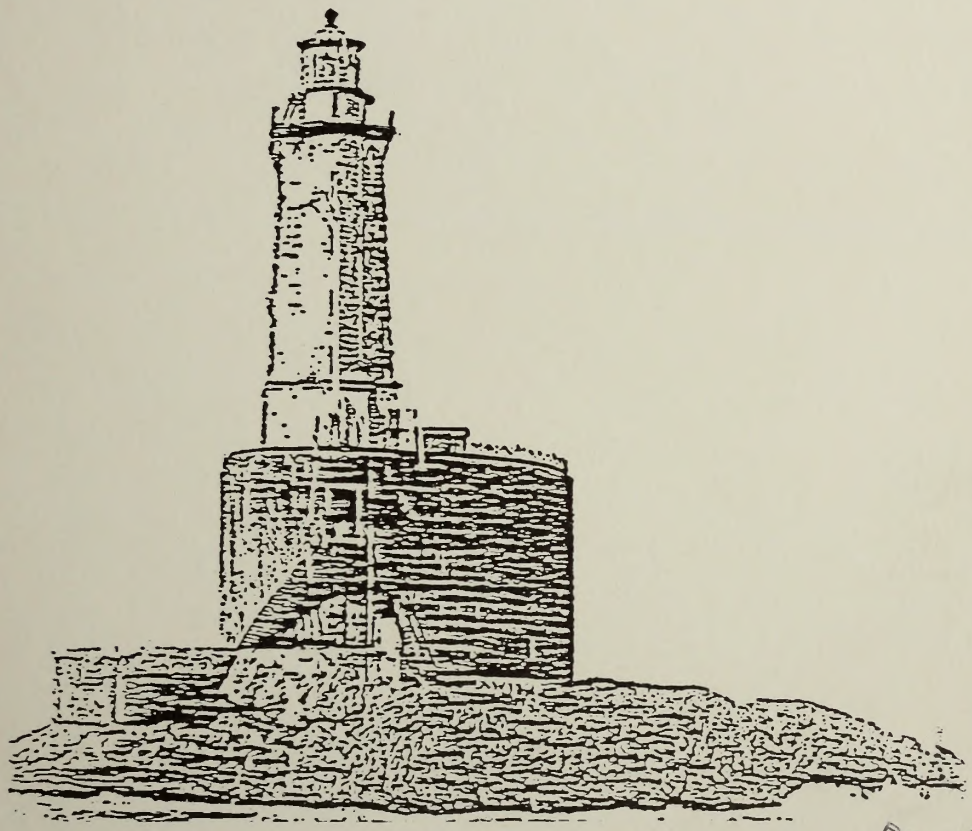
DEPARTMENT OF THE INTERIOR

POCS REFERENCE PAPER NO. 53-1

Proposed Oil And Gas Transportation

Scenarios Of Proposed OCS Sale No. 53

Offshore Central And Northern California



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PREFACE

The purpose of POCS Paper No. 53-1 was to propose, describe and analyze the alternative pipeline and tanker transportation scenarios from the five Proposed Sale No. 53 tract areas to potential refineries.

Acknowledgement is made to Herbert S. Emmrich, Chief of the Environmental Division, Pacific Outer Continental Shelf Office, Los Angeles, California, for providing invaluable direction and information.

POCS Reference Paper No. 53-1 was written by Robert M. Yamasaki, Environmental Engineer, Pacific Outer Continental Shelf Office, Los Angeles, California.

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Sale No. 53 Proposed Oil and Gas Transportation Scenarios

1.0 Introduction

Three Scenarios are proposed to transport oil and gas from the Sale No. 53 tracts, and they are: 1) Scenario No. 1, mixed mode of pipelines and tankers to California refineries; 2) Scenario No. 2, 100% tankering to California refineries; and Scenario No. 3) tankering to Galveston Texas, via Panama Canal for distribution to the Petroleum Administraton for Defense District (PADD) 3 refineries, Gulf of Mexico.

In each of the above Scenarios, except for the Bodega area, gas is transported by pipelines to shore and is connected to existing gas pipelines. The three Scenarios are illustrated in Figures 1-4.

Two data sources were used in developing the above three Scenarios, and they are: 1) the mean probability data given in the December 1978 U.S. Geological Survey's preliminary data for Sale No. 53; and 2) existing, readily available information.

The proposal is presented in the following three sections: System Analysis, Design Analysis, and Cost Analysis. The System Analysis describes the reasoning for transporting crudes to California and PADD 3 refineries. The Design Analysis includes the hardware, pipelines and tankers, compatible with each Scenario. The Cost Analysis presents the relative cost comparison in dollars per barrel between each Scenario.

2.0 System Analysis

2.1 General

The production of Sale No. 53 oil and gas is estimated to start in 1986 and continue until 2005 with the maximum total daily production occurring in 1990. Of the five production areas, the Eel River area produces only gas. The other four areas produce oil and gas (processed offshore) except Scenario No. 1A, option to Scenario No. 1.

Based on best available information the Sale No. 53 produced crude oil properties are tabulated in Table No. 1. The API ranges from 6 to 40 and sulfur by percent weight from less than 1 1/2 to 4 percent. For the analysis the following is used: API of 24 and sulfur of 2.5.

Sale No. 53 crude would be competing for the California and PADD 3 market with the Alaskan North Slope (ANS) crude. To reduce excess ANS crude in the West Coast, the Northern Tier Pipelines is proposed. The Northern Tier Pipeline would start at Low Point, Washington and terminate at Clearbrook, Minnesota. The pipeline is designed to transport 933,000 BOD.

2.2 Processed in California Refineries

Sale No. 53 crude oil could be transported and refined in California for the following reasons:

1. California refineries have capabilities to process Sale No. 53 crude oil. Table No. 2 tabulates by area the current California refineries. Table No. 3 lists the estimated current California refineries capacities to process Sale No. 53 crude with minimum blending of foreign crude and with minimum processing changes. Sale No. 53 crude processing estimates are based on an assumption that API and sulfur contents are the limiting factors. Sale No. 53 crude properties on API and sulfur are given in Table No. 1. Table No. 4 indicates that the 20-year average of Sale No. 53 crude production could be 6% of the refining capacity of Table No. 3 for San Francisco Bay area and 8.2% in the Los Angeles basin.

2. Alaskan North Slope crude is transported by 798 miles of pipeline from Prudhoe Bay to Valdez, 2,100 nautical miles (NM) by tanker from Valdez to the Los Angeles basin, or 1,760 NM to the San Francisco Bay area. In comparison, Sale No. 53 crude is from 56 to 156 NM from the platforms to the refineries in the San Francisco Bay area, and 174 NM from the platforms to the Ports of Long Beach and Los Angeles. Therefore, the transportation cost to California refineries should be far less for Sale No. 53 crude than for ANS crude.

3. Chevron and Shell are proposing to transport offshore crude to refineries in the Los Angeles basin. They would probably have their crude processed at their refineries. Chevron is planning to transport crude from the proposed Platform Grace in the East Santa Barbara Channel OCS to their refinery at El Segundo. Crude from platform Grace is estimated to be API of 28 and sulfur of 2%. Table No. 3 indicates that Chevron's refinery at El Segundo could have the capacities to process crude of any API and sulfur of any limit. Shell is also planning to transport their share of crude from the proposed platform Elly in San Pedro Bay to their refinery at Wilmington. Crude from platform Elly is estimated to be API of 14 to 16 and sulfur of 3 to 4%. Table No. 2 indicates that Shell's refinery at Wilmington could be limited to API of 30 and sulfur of 1%. Shell[1] is investigating the possibility of processing their share of the crude from platform Elly by blending, or increasing the sulfur plant capacity, or other processing changes. In comparison, Sale No. 53 crude properties are expected to be API of 24 and sulfur of 2.5%. Therefore, discoveries in Sale No. 53 tracts could be refined in the California refineries.

4. Shortage of Alaska North Slope (ANS) crude in California could occur if the Northern Tier Pipeline and the swap of ANS crude for Mexican crude are approved. Then, Sale No. 53 crude could be in demand in California. The Northern Tier Pipeline could transport approximately 933,000 BOD of ANS crude to the northern states' refineries. The pipeline could be constructed and operational two years after receipt of all permits and right-of-way approval. The production could start at 540,000 BOD and within 4 years to 933,000 BOD. The swap of ANS crude for Mexican crude would include an agreement between Japan-Mexico-U.S.A. to transport ANS crude to Japan in exchange for Mexican crude. In 1977 Mexico exported 200,000 BOD and is estimated to export 5 million BOD in the year 2000. In 1978 the Trans-Alaskan Pipeline System transported 1.2 million BOD from Valdez of which 600,000 BOD was absorbed in the West Coast. By year 2000, it is estimated that 2.4 million BOD would be shipped out of Valdez.

2.3 Processed in PADD 3 Refineries

Sale No. 53 crude could be transported and refined in the PADD 3 refineries for the following reasons:

1. Currently, aproximately 1.5 million BOD of ANS crudes are transported from Valdez to the West and East coasts. By year 2000 it is estimated that 2.4 million BOD would be transported. Currently, the West coast refineries could process 800,000 BOD (675,000 California and 125,000 Washington) and the PADD 3 refineries about 1,200,000 BOD. Therefore, without other means, there would be excessive ANS crude in the West coast. Other means would include Northern Tier Pipeline and swap with Japan and Mexico.

2. Exxon[2] plans to transport by tanker the Santa Ynez crude from the Santa Barbara Channel to the Gulf or East coast because of no market in the Pacific coast. The crude is of poor quality, low API (18) and high sulfur content (4%), resulting in having very few refineries in the Pacific coast that can or want to process the crude.

---

[1]Kindschy, E.O., June 11, 1979. Shell Oil Company, Houston Texas. Personal communication.

[2]Sollin, R.H., Nov. 22, 1978. Gulf, East Coast Markets eyed by Exxon officals. News-Press.

3.0 Design Analysis

3.1 General

Transportation of oil and gas from the offshore production platforms is illustrated in Figures 1-4 as three transportation scenarios. Oil is transported as follows: Scenario No. 1, mixed mode by pipelines and tankering, and Scenario No. 2, 100% tankering, are analyses on transportation of oil to the California refineries. Scenario No. 3, tankering via the Panama Canal, is an analysis on transportation of oil to the Petroleum Administration for Defense District (PADD) 3 refineries. Gas is transported by pipelines, except for Bodega area, to the nearby shore and connected to existing pipelines. The Eel River area produces only gas. The other four areas produce oil and gas.

Design of the three scenarios is based on the U.S. Geological Survey's preliminary mean probability data which is tabulated in Table No. 5. Each area has several production platforms. However, for purposes of not disclosing the platform location and for simplifying the scenarios, the approximate centers of the areas were set as the production location.

Table No. 6 indicates the limiting tanker sizes at various ports. The size of tankers entering the San Francisco Bay area refineries is limited at the entrance to the Bay to 120,000 dead weight ton (dwt). Several refineries in the Los Angeles basin have pipelines connected from the refineries to the Ports of Los Angeles and Long Beach. The maximum tanker size to the Los Angeles basin is: 100,000 dwt to Port of Los Angeles, 165,000 dwt to Port of Long Beach, and 165,000 dwt to Chevron's refinery at El Segundo. The proposed Alaskan tanker fleet from Valdez, Alaska to the proposed terminal (formerly SOHIO) at Port of Long Beach is: 80,000, 120,000, and 165,000 dwt. Maximum tanker through the Panama Canal is limited to fully loaded 50,000 dwt, although tankers of up to 90,000 dwt can transmit with about 60,000 dwt of cargo.

3.2 Scenario No. 1

Design information on Scenario No. 1, mixed mode of pipelines and tankers, is given in Table No. 7. The Eel River area produces only gas which is transported from an offshore gathering platform in a 10-in. pipeline for 13 miles to shore, and continues onshore for 5 miles to connect to an existing 12-in. PG&E pipeline. Preliminary investigation indicates possible environmental conflicts which include the nesting grounds of the American peregrine falcon. This endangered species is found in the Table Bluffs area and Humboldt Bay wetland habitat, both of which exist near one of the likely pipeline routes. It is anticipated however, that mitigation or avoidance of adverse impacts can be accomplished in the siting and laying of the pipeline.

The Point Arena area produces gas and oil. The oil is transported about 156 nautical miles (NM) in a 25,000 dwt tanker to refineries in the San

Francisco Bay area. The estimated turnaround time for the tanker is 4.5 days. The gas is transported about 13 miles to shore in 10-in. pipeline. This pipeline is near Mendocino and continues onshore for about 33 miles and connects with existing 12-in. PG&E gas pipelines.

The Bodega area produces gas and oil. The gas is reinjected into the well. The oil is transported about 70 NM in a 15,000 barrel (bbls) barge to refineries in the San Francisco Bay area. The estimated turn around time for the barge is 2.8 days.

At the Santa Cruz area gas and oil are transported by pipelines to shore near Half Moon Bay. The gas is transported in 10-in. pipeline for 17 miles offshore and 7 miles onshore and connects with existing 30-in. PG&E gas pipeline. The oil is transported in 12-in. pipeline for 17 miles offshore and 87 miles onshore following the existing pipeline route and connecting to the refineries in the San Francisco Bay area.

At the Santa Maria area gas and oil are transported by pipeline to shore near Santa Maria River and follows the river to U.S. Highway No. 101 where gas pipeline connects with the existing Southern California Gas (SCG) pipeline. The oil pipeline follows U.S. Highway No. 101 until the pipeline connects with the proposed Santa Barbara County pipeline at Las Flores Canyon. The Santa Barbara pipeline would connect with refineries in the Los Angeles basin. Gas is transported in 16-in. pipeline for 16 miles offshore and 14 miles onshore and connects with existing 16-in. SCG gasline. Oil is transported in 20-in. pipeline for 16 miles offshore and 54 miles onshore and connects with proposed Santa Barbara pipeline.

3.3 Scenario No. 2

Design information on Scenario No. 2, 100% tankering, is given in Table No. 8.

Gas pipelines for the Eel River area is same as Scenario No. 1.

Oil tanker transportation for the Point Arena area is the same as Scenario No. 1. The gas is piped to shore and is same as Scenario No. 1.

Gas and oil transportation for the Bodega area is the same as Scenario No. 1.

The Santa Cruz area produces gas and oil. The gas is piped to shore and is the same as Scenario No. 1. The oil is transported about 56 NM in a 100,000 bbls barge to refineries in the San Francisco Bay area. The turn around time is 3 days.

The Santa Maria area produces gas and oil. The gas is piped to shore and is the same as Scenario No. 1. The oil is transported in a 28,000

dwt tanker for about 174 NM via Point Conception to the Point Fermin sea lanes to the Ports of Los Angeles and Long Beach. Turn around time is 3 days.

3.4 Scenario No. 3

Scenario No. 3, Tankering to Galveston via Panama Canal, is given in Table 9. Gas transportation is the same as Scenario No. 1. Oil from Point Arena, Santa Cruz and Santa Maria is transported by 45,000 dwt tankers to Galveston via Panama Canal. Oil from Bodega is transported by 25,000 dwt tankers. Maximum tanker size that can pass through the Panama Canal is 45,000 dwt, fully loaded. Each tanker would take between 27 to 29 days of turn around time. The distance from the marine terminal to Galveston is between 4400 to 4738 NM. There are other nearby ports to Galveston such as Freeport, Houston and Lake Charles. For matter of convenience, Galveston was selected.

3.5 Scenario No. 1A

Scenario No. 1A is an option to Scenario No. 1. The transportation route for No. 1A is the same as No. 1 except as follows: 1) Eel River - gas processing plant is located about 4 miles inland along the No. 1 pipeline route; 2) Point Arena - offshore gas pipeline is about 22 miles and connects with onshore gas processing plant which is located about 2 miles inland near Manchester. Onshore pipeline follows State Highway No. 253 for about 35 miles and ties with existing 12-inch PG & E pipeline near Ukiah; 3) Santa Cruz and Santa Maria - oil and gas processing plants are located about 2 miles inland along the No. 1 pipeline route.

The onshore processing plants could occupy the following areas: 1) Eel River - about 11 acres for gas processing plant; 2) Point Arena - about 9 acres for gas processing plant; 3) Santa Cruz - about 13 acres for oil and gas processing plant and 2-50,000 barrel oil storage tanks; 4) Santa Maria - about 41 acres for oil and gas processing plant and 2-170,000 barrle oil storage tanks.

4.0 Cost Analysis

4.1 General

A preliminary cost estimate is made to compare the cost between each transportation Scenario, between transportation of oil by pipeline or by tankers, and between transportation of gas by pipeline at each area. For cost comparison, cost per unit for 20 year average production is used. The cost per unit[1], considered as tariff, is estimated at 25% of first investment which is averaged over 20 years of production and is expressed:

$$\text{Tariff of dollar per unit} = \frac{(0.25)\ (\text{Investment Cost})}{\text{20 Years average annual production}}$$

Cost anaylsis is based on available information. The 20 year average annual production is calculated from the U.S. Geological Survey's data[2]. The investment cost for onshore pipeline is based on Hallanger's Report[1]. Cost for an offshore pipeline is estimated as 1.67 times the cost of an onshore pipeline. This estimate is based on the offshore and onshore pipeline cost given in the Beta report[3]. Pipeline cost in this report is at the January 1979 level.

The tankering cost is based on A.D. Little's report[4] which includes investment and operating cost at the 1975 level. Twenty percent of the tankering cost is assumed as investment cost. An inflation factor of 1.7 is used to bring the 1975 cost to January 1979 cost level.

4.2 Analysis

Tables Nos. 10-12 tabulate the cost for the three Scenarios. Each Scenario indicates the relative cost per unit for oil and gas pipelines and tankering. Table No. 13 summarizes the transportation cost for oil by each Scenario. Scenario No. 2, 100% tankering, costs $0.34 per barrel. Scenario No. 3, Tanker to Gulf of Mexico via Panama Canal, costs $2.31 to 2.64 per barrel.

Related cost between pipeline and tankering is given in Table No. 14. Transporting oil from Santa Cruz to refineries at San Francisco Bay area by tanker is $0.32 per barrel and by pipeline is $1.63 per barrel. Transporting oil from Santa Maria to Los Angeles Basin by tankering is $0.37 per barrel and by pipeline is $1.40 per barrel. Therefore, pipeline costs are about 5 times tankering costs. Pipeline costs include offshore and onshore pipelines.

Table No. 15 summarizes the cost of transporting gas by pipeline.

References

[1]Hallanger Engineers, Inc., October 6, 1978. Final-Report Santa Barbara Onshore Pipeline Study.

[2]U.S. Geological Survey, December 1978. Preliminary design data for Sale No. 53.

[3]State Lands Commission, California, Port of Long Beach, U.S. Geological Survey, December 1, 1978. EIR/EA Shell OCS Beta Unit Development.

[4]Authur D. Little, Inc., July 1976. Outer Continental Shelf Oil and Gas Costs and Production Volume: Their Impact on the Nation's Energy Balance to 1990.

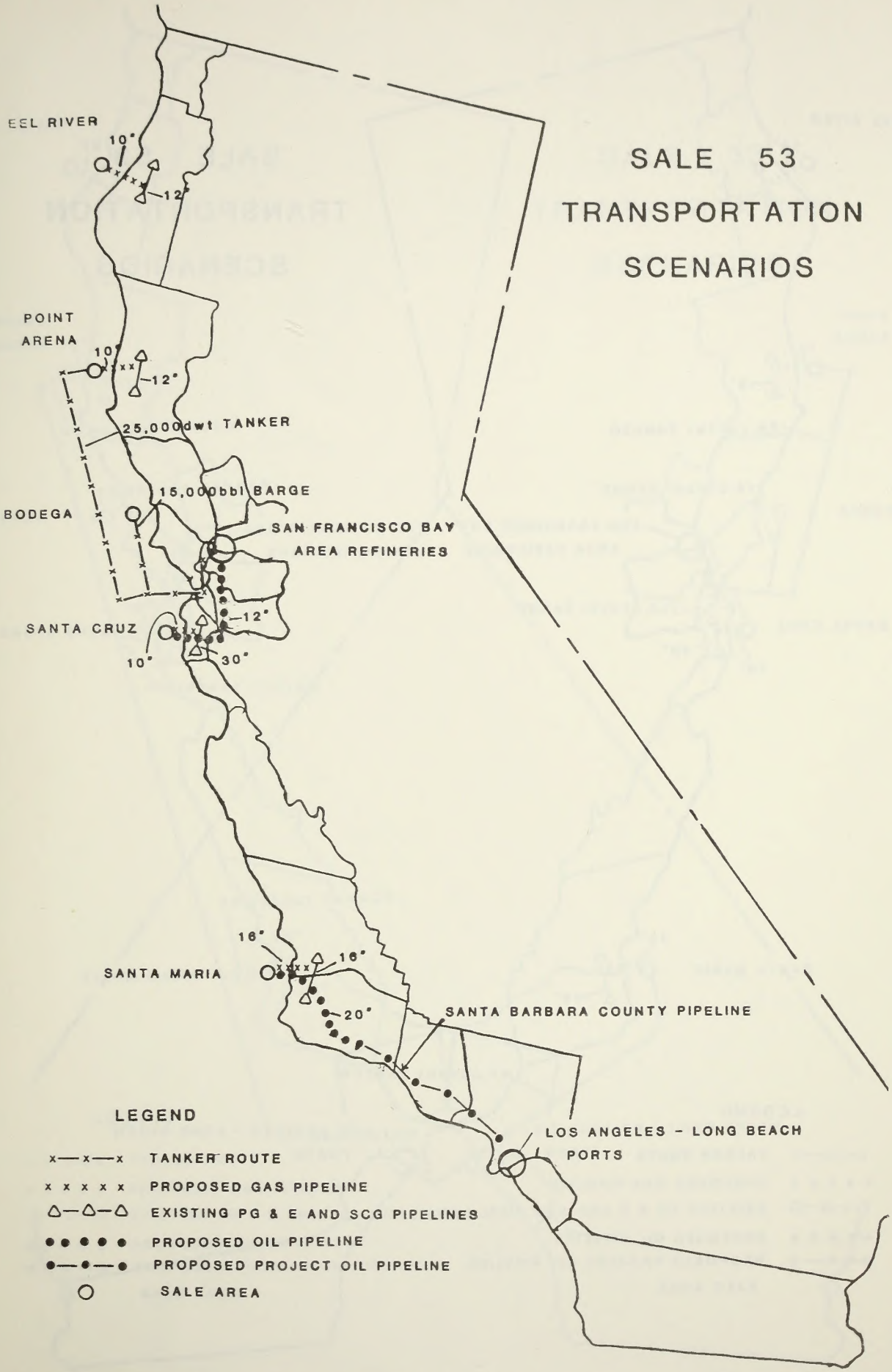

FIGURE NO. 1 SCENARIO NO. 1

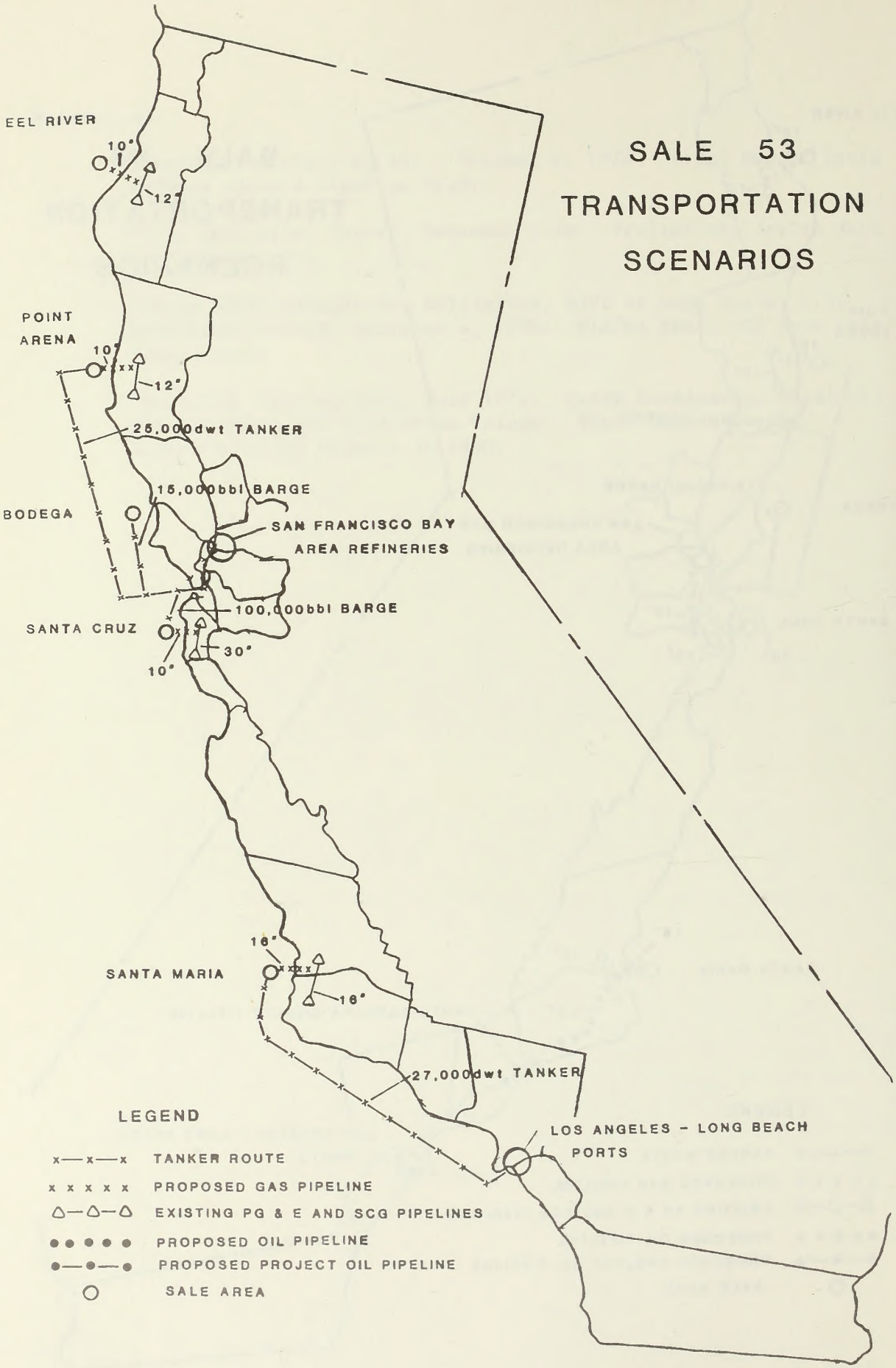

FIGURE NO. 2 SCENARIO NO. 2

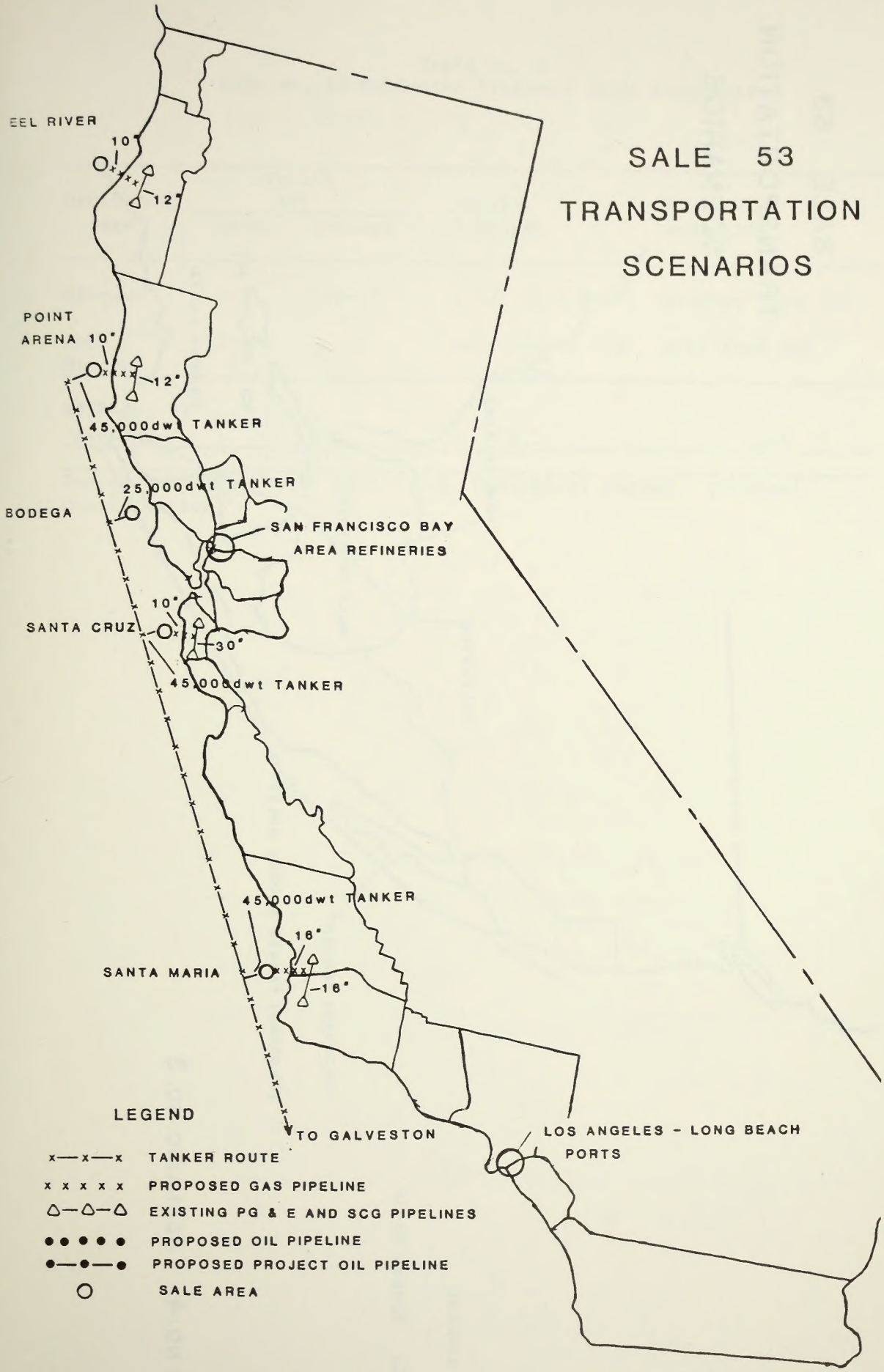

FIGURE NO. 3 SCENARIO NO. 3

SALE 53
TRANSPORTATION
SCENARIOS

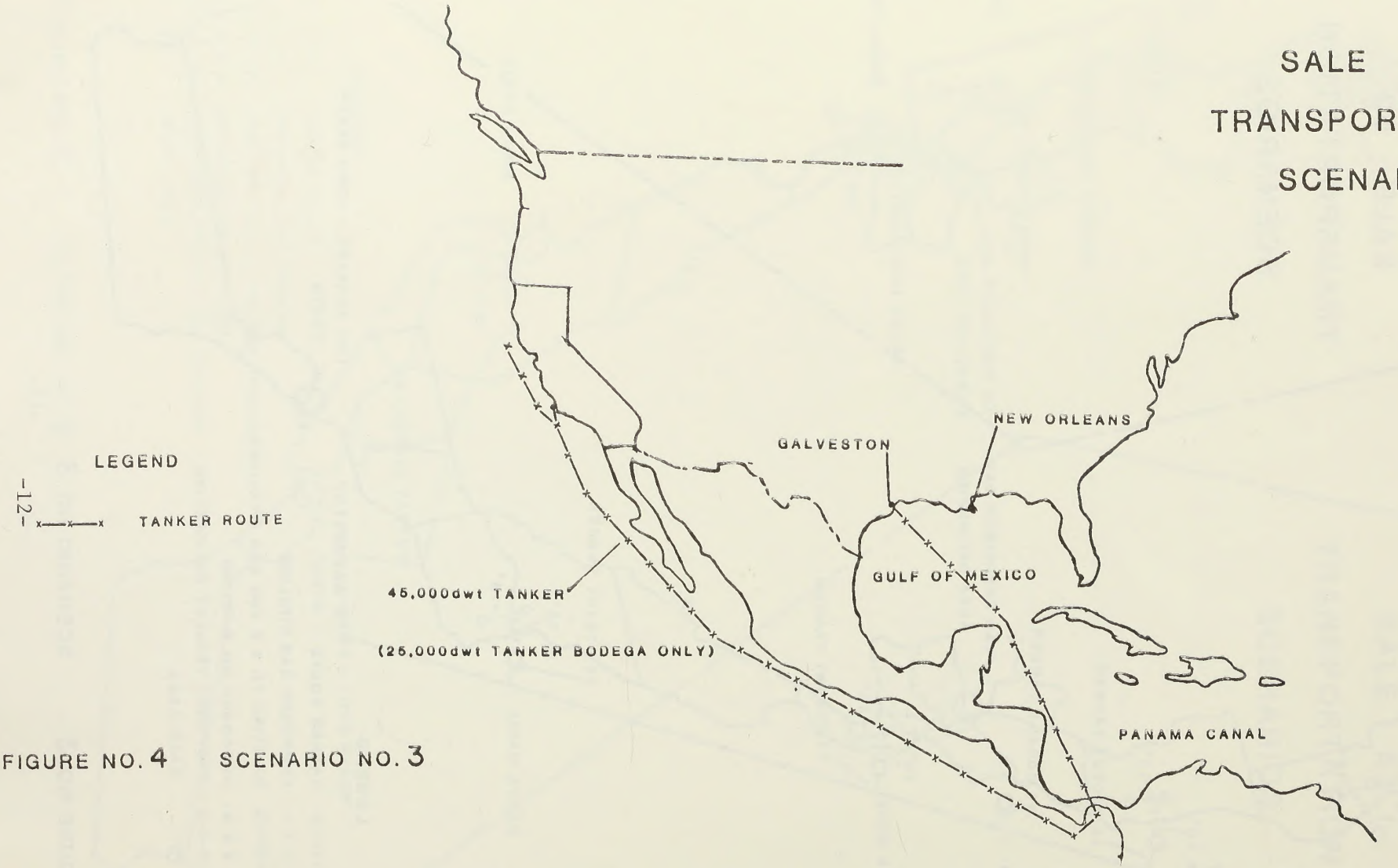

FIGURE NO. 4 SCENARIO NO. 3

Table No. 1
Sale No. 53 Estimated Produced Crude Properties

Geological Age	Gravity API		Sulfur % Weight	% of Crude Available
	Range	Average		
Miocene	6-31	16-17	1 1/2 to 4	Greater than 50%
Pre-Miocene	15-40	31	Less than 1 1/2	Less than 50%
Sale No. 53 Average		24	2.5	100%

Source: Griggs, D.G. 1979. U.S. Geological Survey. Personal Communication.

Table No. 2

Refineries in California

Company and Location[1]	Capacity[1] Barrels Per Calender Day	Gravity[2] Required (API)	Sulfur[2] Limit (% weight)
Los Angeles Basin (18)			
Atlantic Richfield Co.-Carson	180,000	10-70	1.3
Basin Petroleum Inc.-Long Beach	NR		
Champlin Petroleum Co.-Wilmington	31,200	17-23	1.5
Chevron USA Inc.-El Segundo	405,000	Any	Any
DeMenno Resources-Compton	10,000		
Douglas Oil Co.-Paramount	46,500	27-31	2.5
Eco Petroleum Inc.-Signal Hill	5,600		
Edgington Oil Co. Inc.-Long Beach	29,500	20-25	Any
Fletcher Oil & Refining Co.-Carson	25,000	29-36	0.3
Golden Eagle Refining Co.-Carson	16,500	17-40	1.0
Gulf Oil Co.-Santa Fe Springs	51,500	29-31	1.3
Lunday-Thagard Oil Co.-South Gate	12,000	33-34	1.5
Macmillian Ring-Free Oil Co. Inc.-Signal Hill		20-35	1.5
Mobil Oil Corp.-Torrance	123,500	20-25	1.5
Powerline Oil Co.-Santa Fe Springs	44,120	25-35	1.5
Shell Oil Co.-Wilmington	108,000	30	1.0
Texaco Inc.-Wilmington	75,000	20-35	2.0
Union Oil Co. of California-Los Angeles	108,000	18-40	1.8
San Francisco Bay Area (6)			
Chevron USA-Richmond	365,000	Any	Any
Exxon Co.-Benicia	99,000	13-40	1.5
Pacific Refining Co.-Hercules	85,000	54	0.2
Shell Oil Co.-Martinez	104,000	--	--
Tosco Corp.-Martinez	137,000	Any	1.8
Union Oil Co. of California-Rodeo	111,000	13-36	2.0
San Joaquin Valley (12)			
Beacon Oil Co.-Hanford	12,300	25-35	1.0
Chevron USA Inc.-Bakersfield[1]	26,000	30-32	1.0
Golden Bear Division, Witco Chemical Corp.-Oildale	10,500	13-15	1.5
Kern County Refinery Inc.-Bakersfield	15,900	25-30	1.5

Table No. 2 (cont.)

Company and Location[1]	Capacity[1] Barrels Per Calender Day	Gravity[2] Required (API)	Sulfur[2] Limit (% weight)
Mohawk Petroleum Corp. Inc.- Bakersfield	22,100	28	1.0
Road Oil Sales-Bakersfield	1,500	--	--
Sabre Refining Inc.-Bakersfield	NR	20-35	2.0
San Joaquin Refining Co.-Oildale	27,000	26 Max.	Any
Sierra Anchor-McKittrick	10,000		
Sunland Refining Corp.-Bakersfield	15,000	20-35	1.0
Tosco Corp.-Bakersfield	NR	20	1.5
West Coast Oil Co.-Oildale	19,000	12-30	0.7
Other Areas (5)			
Douglas Oil Corp.-Santa Maria	9,500	10-12	5.0
Newhall Refining Co. Inc.-Newhall	17,600	17-25	1.3
Oxnard Refining Co.-Oxnard	2,500	--	--
USA Petroluem Corp.-Ventura	20,000		
Union Oil Co.-Arroyo Grande[3]	41,000	12-24	5.0
Total for California	2,453,620		

[1]Oil and Gas Journal. March 26, 1979. Annual Refining Report

[2]The Western Division Naval Facilities Engineering Command. June 19, 1976. Environmental Impact Assessments of Alternative Means for Transporting Crude Oil from Naval Petroleum Reserve No. 1, Elk Hills, Topman, California to Marketing Terminal.

[3]Department of Energy. January 1, 1978. Energy Data Report, Petroleum Refineries Annual

NR = Not Reported

Table No. 3

Estimated Current California Refineries Capacity
to Process Sale No. 53 Crude

Refineries	Refinery Capacity Barrels per Calender Day BCD	Gravity Required ADI	Sulfur Limit (% weight)
San Francisco Bay Area			
Chevron USA, Richmond	365,000	Any	Any
Union Oil Co. of Ca., Rodeo	111,000	13-36	2.0
Tosco Corp., Martinez	137,000	Any	1.8
Total	613,000		
Los Angeles Basin			
Chevron USA, El Segundo	405,000	Any	Any
Douglas Oil Co., Paramount	46,500	27-31	2.5
Edgington Oil Co. Inc., Long Beach	29,500	20-25	Any
Texaco Inc., Wilmington	75,000	20-35	2.0
Union Oil of Ca., Los Angeles	108,000	18-40	1.8
Total	664,000		
Total for California	2,453,620		

Table No. 4

Estimated Percent of Sale No. 53 Crude
of California Refineries

Sale No. 53 Production Barrels per Day (BOD)		Refineries in Table No. 3			% of Sale 53 Crude of Refinery Capacity	
20 years Average	1990 Max. System	Area	Capacity BOD	Sulfur Ranges % Weight	20 Years Average	1990 Max. System
36,849	77,800	San Francisco Bay	613,000	1.8-Any	6.0	12.7
54,699	109,300	Los Angeles Basin	664,000	1.8-Any	8.2	16.5

Table No. 5

Mean Probability Data by U.S. Geological Survey for
Sale No. 53, Draft Environmental Statement
Preliminary Information, December 1978

Production Area	Production 1990 Daily Production Oil BOD	Gas MCFD	1986-2006 Total Oil MB	Gas MMCF
Eel River	--	49,900	--	180,200
Point Arena	38,600	40,000	129,100	134,200
Bodega	5,400	5,100	23,200	22,100
Santa Cruz	33,800	35,600	116,700	123,000
Santa Maria	109,300	114,000	399,300	408,800

Notes:

BOD = barrel per day
MCFD = 1,000 cubic feet per day
MB = 1,000 barrels
MMCF = 1,000,000 cubic feet

Table No. 6

Limiting Tanker Sizes at Various Ports

Terminal	Limiting Tanker Deadweight Ton (dwt)	References
San Francisco Bay Area Refineries		
- Entrance to San Francisco Bay	120,000[2,4]	West Coast
- Chevron at Richmond	17,000 to 150,000[1]	Deepwater Port Facility Study
- Union at Rodeo	Up to 50,000[2]	(Summary Report) Corps of Engineers
- Phillips at Martinez	Light loaded 130,000	July 1973
Los Angeles Basin Refineries		
- Port of Los Angeles	100,000[3]	51 feet max draft John McMullin LNG
- Port of Long Beach	165,000	60 feet max draft p. 3-73
- Refinery Terminal at Los Angeles Port		
- Edgington	40,000[2]	
- Douglas-Continental	120,000[3]	
- Union	130,000[3]	
- Texaco Terminal at Long Beach Port	130,000[2]	
- Chevron at El Segundo	165,000[1]	
Proposed Terminal Long Beach Port (Formerly SOHIO)		
- Minimum tanker	70,000	DOI ES Crude Oil Transportation
- Proposed tankers	80,000; 120,000	System Valdez, Alaska to Midland, Texas
	165,000	(SOHIO), Executive Summary
Panama Canal	50,000[2,4]	

[1]Magee, D.T. Aug. 2, 1979. Chevron's letter to Pacific OCS Office, BLM.

[2]Fully loaded.

[3]Lightly loaded.

[4]Freeman, R.M. Oct. 15, 1979. Exxon's letter to Mr. Hank Wright, WOGA.

Table No. 7

Pipeline and Tanker Design Scenario No. 1 Mixed Mode Pipeline and Tanker

Area	1990 Flowrate Mean Scenario		Pipelines								Tanker-Barge-Storage Tank				
			Oil				Gas								
	Oil BOD	Gas MCFD	Dia. Inch	Distance Miles Off-shore	Distance Miles On-shore	Tie-in	Dia. Inch	Distance Miles Off-shore	Distance Miles On-shore	Tie-in	Distance to Terminal Nautical Miles	Vessel Capacity bbls (one Req'd)	Turn Around Time Day	Offshore Storage Vessel & Pump & SBM bbls one req'd	Tanker Terminal
Eel River	--	49,900	--	--	--	--	10	13	5	12" PG&E	--	--	--	--	
Point Arena	38,600	40,000	--	--	--	--	10	13	33	12" PG&E	156	175,000 Tanker	4.5	200,000	Refineries in San Francisco Bay Area
Bodega	5,400	5,100	--	--	--	--	--	--	--	--	70	15,000 Barge	2.8	100,000	Refineries in San Francisco Bay Area
Santa Cruz	33,800	35,600	12	17	87	Refi-neries S.F.	10	17	7	30" PG&E	--	--	--	--	
Santa Maria	109,300	114,000	20	16	54	*	16	16	14	16" SCG	--	--	--	--	
TOTAL	187,100	244,600													

Note:

*Tie with proposed Santa Barbara County pipeline (Hallanger) at Las Flores Canyon

Table No. 7A

Pipeline and Tanker Design Scenario No. 1A Mixed Mode Pipeline and Tanker

Area	Onshore Processing Plant		Pipelines								Tanker-Barge-Storage Tank				Tanker Terminal
			Oil				Gas								
	Type	Oil Storage Tank bbls	Dia. Inch	Distance Miles Off-shore	Distance Miles On-shore	Tie-in	Dia. Inch	Distance Miles Off-shore	Distance Miles On-shore	Tie-in	Distance to Terminal Nautical Miles	Vessel Capacity bbls (one Req'd)	Turn Around Time Day	Offshore Storage Vessel & Pump & SBM bbls one req'd	
Eel River	Gas	None	--	--	--	--	10	13	5	12" PG&E	--	--	--	--	
Point Arena	Gas	None	--	--	--	--	10	13	33	12" PG&E	156	175,000 Tanker	4.5	200,000	Refineries in San Francisco Bay Area
Bodega	None	None	--	--	--	--	--	--	--	--	70	15,000 Barge	2.8	100,000	Refineries in San Francisco Bay Area
Santa Cruz	Oil & Gas	2-50,000	12	17	87	Refi-neries S.F.	10	17	7	30" PG&E	--	--	--	--	
Santa Maria	Oil & Gas	2-170,000	20	16	54	*	16	16	14	16" SCG	--	--	--	--	
TOTAL															

Note:

*Tie with proposed Santa Barbara County pipeline (Hallanger) at Las Flores Canyon

Table No. 8

Pipeline and Tanker Design Scenario No. 2 100% Tankering

Area	1990 Flowrate Mean Scenario		Tanker-Barge-Storage Tank				Pipeline Gas				Tanker Terminal
	Oil BOD	Gas MCFD	Distance to Terminal Nautical Miles	Vessel Capacity bbls one Required	Turn Around Time Day	Offshore Storage Vessel & Pump & SBM bbls One req'd	Dia Inch	Distance Miles Offshore	Distance Miles Onshore	Tie-in	
Eel River	--	49,900	--	--	--	--	10	13	5	12" PG&E	
Point Arena	38,600	40,000	156	175,000 (Tanker 25,000 DWT)	4.5	200,000	10	13	33	12" PG&E	Refineries in San Francisco Bay Area
Bodega	5,400	5,100	70	15,000 Barge	2.8	100,000	--	--	--	--	"
Santa Cruz	33,800	35,600	56	100,000 Barge	3.0	100,000	10	17	7	30" PG&E	"
Santa Maria	109,300	114,000	174	200,000 (Tanker 27,000 DWT)	3.0	450,000	16	16	14	16 SCG	Refineries Connected to Los Angeles-Long Beach Ports
TOTAL	187,100	244,600									

Table No. 9

Pipeline and Tanker Design Scenario No. 3 Tankering to Galveston via Panama Canal

Area	1990 Flowrate Mean Scenario Oil BOD	1990 Flowrate Mean Scenario Gas MCFD	Tanker-Barge-Storage Tank: Terminal	Distance to Terminal Nautical Miles	Vessel Capacity bbls	Turn Around Time Day	Storage Tank bbls	Pipeline: Oil Dia. Inch	Oil Distance Mile Off-shore	Oil Distance Mile On-shore	Oil Tie-in	Gas Dia. Inch	Gas Distance Mile Off-shore	Gas Distance Mile On-shore	Gas Tie-in
Eel River	--	49,900	--	--	--	--	--	--	--	--	--	10	13	5	12" PG&E
Point Arena	38,600	40,000	Galveston	4738	3 - 45,000 dwt Tanker (333,500 bbls)	29	200,000[1]	--	--	--	--	10	13	33	12" PG&E
Bodega	5,400	5,100	Galveston	4661	2 - 25,000 dwt (175,000 bbls)	28	100,000[1]	--	--	--	--	--	--	--	--
Santa Cruz	33,800	35,600	Galveston	4596	3 - 45,000 dwt	28	100,000[1]	--	--	--	--	10	17	7	30" PG&E
Santa Maria	109,300	114,000	Galveston	4400	8 - 45,000 dwt	27	450,000[1]	--	--	--	--	16	16	14	16" SCG

[1]Offshore storage & vessel & pump & SMB

Table No. 10

Transportation Pipelines and Tankers 20 Years Average Cost
Scenario No. 1. Mixed Mode (Pipeline & Tanker) California Refineries

Area	Pipeline						Tankers			
	Oil			Gas						
	Terminal	Dia. In.	Cost per Barrel Dollar	Terminal	Dia. In.	Cost per MCF Dollar	Terminal	Vessel Size	Facility	Cost Barrel Dollar
Eel River	--	--	--	12" PG&E	10	0.21	--	--	--	--
Point Arena	--	--	--	12" PG&E	10	0.56	San Francisco Bay Area	175,000 bbls (25,000 dwt)	--	0.36
Bodega	--	--	--	--	--	--	San Francisco Bay Area	15,000 bbls Barge	--	0.36
Santa Cruz	San Francisco Bay Area	12	1.63	30" PG&E	10	0.40	--	--	--	--
Santa Maria	*Los Angeles Basin	20	*1.40	16" SCG	16	0.22	--	--	--	--

*Tie with Proposed Santa Barbara County Pipeline (Hallanger) at Las Flores Canyon.
Cost/barrel includes proposed Santa Barbara County pipeline

Table No. 11

Transportation Pipelines and Tankers 20 Years Average Cost
Scenario No. 2. 100% Tankering California Refineries

Area	Pipeline						Tankers			
	Oil			Gas						
	Terminal	Dia. In.	Cost per Barrel Dollar	Terminal	Dia. In.	Cost per MCF Dollar	Terminal	Vessel Size	Facility	Cost Barrel Dollar
Eel River	--	--	--	12" PG&E	10	0.21	--	--	--	--
Point Arena	--	--	--	12" PG&E	10	0.56	San Francisco Bay Area	175,000 bbls (25,000 dwt)	--	0.36
Bodega	--	--	--	--	--	--	San Francisco Bay Area	15,000 bbls Barge	--	0.36
Santa Cruz	--	--	--	30" PG&E	10	0.40	San Francisco Bay Area	100,000 bbls Barge	--	0.32
Santa Maria	--	--	--	16" SCG	16	0.22	Los Angeles/ Long Beach Ports	200,000 bbls (28,000 dwt)	--	0.37

Table No. 12

Transportation Pipelines and Tankers 20 Years Average Cost
Scenario No. 3. Tankering to Galveston Via Panama Canal

Area	Pipeline						Tankers			
	Oil			Gas						
	Terminal	Dia. In.	Cost per Barrel Dollar	Terminal	Dia. In.	Cost per MCF Dollar	Terminal	Vessel Size	Facility	Cost Barrel Dollar
Eel River	--	--	--	12" PG&E	10	0.21	--	--	--	--
Point Arena	--	--	--	12" PG&E	10	0.56	Galveston	335,000 bbls (45,000 dwt)	--	2.50
Bodega	--	--	--	--	--	--	Galveston	(25,000 dwt) Barge	--	2.64
Santa Cruz	--	--	--	30" PG&E	10	0.40	Galveston	335,000 bbls Barge	--	2.40
Santa Maria	--	--	--	16" SCG	16	0.14	Galveston	335,000 bbls (45,000 dwt)	--	2.31

Table No. 13

Pipeline and Tanker Oil Cost Summary

Scenario	Description	Cost 20 Years Average Dollar/Barrel
1	Pipeline and Tanker to California Refineries	1.20
2	100% Tankering to California Refineries	0.36
3	Tanker to Gulf of Mexico via Panama Canal	2.31 to 2.64

Table No. 14

Pipeline and Tanker Cost Comparison

Area	Transportation	Terminal	Cost 20 Year Average Dollar/Barrel
Santa Cruz	Tankering	San Francisco Bay Area Refineries	0.32
Santa Cruz	Pipeline	San Francisco Bay Area Refineries	1.63
Santa Maria	Tankering	Los Angeles and Long Beach Ports	0.37
Santa Maria	Pipeline	Los Angeles and Long Beach Ports	1.40

Table No. 15

Gas Cost Summary, Pipeline

Area	Terminal	Cost 20 Year Average Dollar/MCF
Eel River	Near Humbolt Bay PG&E	0.21
Point Arena	Near Menodocino PG&E	0.56
Santa Cruz	Near Half Moon Bay PG&E	0.40
Santa Maria	Near Santa Maria River SCG	0.22

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